BEFORE THE NOVA SCOTIA UTILITY AND REVIEW BOARD

In the Matter of an Application by NS Power to Implement
an Advanced Meter Infrastructure /CI47124
(NSUARB M08349)

Evidence of
Alice Napoleon

On Behalf of
Counsel to the Nova Scotia Utility and Review Board

On the Topic of the NS Power Advanced Meter Infrastructure Pilot

January 18, 2018

Public Version

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Alice Napoleon. I am a Senior Associate at Synapse Energy Economics ("Synapse"), located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues including integrated resource planning; economic and technical assessments of energy resources; electricity market modeling and assessment; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients including attorneys general, offices of consumer advocates, public utility commissions, environmental groups, and federal clients such as the U.S. Environmental Protection Agency and the Department of Justice. Synapse has a professional staff of 30 with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. Since joining Synapse in 2005, I have provided economic and policy analysis of electric systems and emissions regulations, with a focus on energy efficiency policies and programs, on behalf of a diverse set of clients throughout the United States and in Canada.

Before joining Synapse, I worked at Resource Insight, Inc., where I supported investigations of electric, gas, steam, and water resource issues, primarily in the context of reviews by state utility regulatory commissions.

I hold a Master's in Public Administration from the University of Massachusetts at Amherst and a Bachelor's in Economics from Rutgers University. My resume is attached as Appendix A.

Q. Please describe your professional experience as it relates to Advanced Metering Infrastructure.

A. In Nova Scotia, I provided evidence last year regarding Nova Scotia Power's (NS Power or the Company) application for approval of an advanced metering infrastructure (AMI) pilot program in Case No. M07767. For the New Jersey Division of Rate Counsel, I reviewed and provided critical analysis of Rockland Electric Company's proposal to implement AMI throughout its New Jersey service territory in support of Tim Woolf's testimony before the New Jersey Board of Public Utilities. I am also familiar with AMI developments and deployments in New York, Hawaii, Maryland, Colorado, and Vermont.

Q. Please describe your professional experience as it relates to cost-benefit analysis.

A. I have significant experience with cost-benefit analysis (CBA), with a focus on energy efficiency programs. In Colorado, Maryland, and South Carolina, I facilitated and provided expert analysis on program costs and benefits for demand-side resource policy working groups. On the national level, I led the team that developed a cost-effectiveness calculator, provided guidance on program design, and developed communications materials and case studies to help state and utility energy efficiency program administrators with implementing offerings to support participation in the U.S. Department of Energy's Superior Energy Performance program.

Since 2009, I have provided extensive and ongoing expert analysis and support for the State of New Jersey regarding its state- and utility-administered energy efficiency and combined heat and power programs. In over a dozen dockets regarding utility-administered efficiency programs, I have conducted expert analysis, provided litigation support, and drafted testimony when appropriate on behalf of the State with respect to a number of issues, including energy efficiency CBA, program implementation, and overlap between utility- and state-administered programs.

Q. Please describe your professional experience with Nova Scotia energy policy.

A. I am very familiar with the energy regulatory environment in Nova Scotia, particularly with respect to demand-side management programs. I provided evidence in Case No. M06247 on behalf of the Nova Scotia Utility and Review Board regarding the 2015 Demand-Side Management Plan. Further, I supported Tim Woolf in Case No. M06733 regarding EfficiencyOne's 2016 to 2018 demand-side management plan.

Q. On whose behalf are you providing evidence in this case?

A. I am providing evidence on behalf of Counsel to the Nova Scotia Utility and Review Board (Board).

Q. What is the purpose of this evidence?

A. The purpose of this evidence is to assess NS Power's proposal to implement AMI in Nova Scotia, describe and present my concerns with the proposal, and provide recommendations to the Board.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. I make the following findings:

- NS Power reports that the AMI project is cost effective, with net benefits of $38 million. However, I find that the CBA includes benefits that are not well supported, omits certain costs, and does not adequately consider the downside risks in its sensitivity analysis of key inputs and assumptions. If adjustments are made to the costs and benefits as suggested herein, the CBA may determine that the project is not cost effective.
- Existing meters will no longer be used and useful.
- NS Power's application does not address coordination with EfficiencyOne and may miss savings opportunities as a result.

Q. Please summarize your primary recommendations.

A. I offer the following recommendations:

- A Critical Peak Pricing (CPP) tariff should be developed prior to Board approval of the AMI project.
- NS Power should adjust its CBA based on the comments in this evidence.
- NS Power should revisit its scenario analyses to determine its exposure if multiple sensitivity areas have negative outcomes.

- The Company should then file the results of the revised CBA and scenario analyses in this case for consideration by the parties.
- While recovery of the cost of existing meters may be appropriate, the Board should not allow a return on the existing meters.

3. BACKGROUND

Q. Please describe the Company's proposal.

A. On October 19, 2017, NS Power filed its AMI Project Application (application or proposal) before the Board. In the application, the Company requested Board approval of a capital work order (CI 47124) for $133 million to deploy advanced (or "smart") meters (CI 47124 AMI Appendix B). NS Power's proposal involves the replacement of about 495,000 conventional meters with smart meters over the period 2018 to 2020 (NS Power application, p. 90). NS Power plans to deploy AMI throughout its service area, with residential, commercial, and industrial customers.[1]

4. NS POWER'S COST-BENEFIT ANALYSIS IS FLAWED

Q. Please describe the Company's cost-benefit analysis.

A. NS Power finds that the AMI roll-out results in a savings of $38.1 million over the assumed 20-year useful life of the project.[2] The benefits and costs of the project, assuming the 20-year useful life, are shown in Confidential CONFIDENTIAL Table 1 below.

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[1] NS Power application, p. 46.

[2] NSPI Application, p. 14.

[redacted]

Q. What are the costs associated with the proposed roll-out of AMI?

A. The capital cost of the project (in nominal dollars) over the period 2015–2020 is estimated to be $133 million. On a net present value (NPV) basis, the costs are roughly [redacted].

Q. Please give an overview of the Company's claimed benefits.

A. NS Power breaks its claimed benefits into Operational Benefits, Grid Modernization Benefits, and Changed Customer Behavior Driven Benefits. Operational Benefits include avoided costs associated with meter reading etc. and comprise about 61 percent of the claimed benefits. Grid Modernization Benefits include savings from load balancing, avoiding the need for a line sensor program, and avoiding operating costs for distributed generation meters. Grid Modernization benefits are roughly 18 percent of the claimed benefits. The remaining 21 percent of the claimed benefits are associated with Changed Customer Behavior Driven Benefits. These benefits include savings due to programs and rate structures that would enable and encourage customers to save energy and reduce peak demand.

Q. Do you have any concerns with NS Power's cost-benefit analysis regarding the AMI roll-out?

A. Yes. The CBA includes benefits that are not well supported, assumes a life of the meters that is too long, and does not include a sensitivity analysis on key inputs and assumptions. Each of these issues is discussed in the remainder of this section. The fact that I do not comment on every aspect of the Company's CBA should not be interpreted to mean that I agree with those aspects.

Some of NS Power's claimed benefits lack support

Q. Do you have concerns with the benefits claimed by the Company in its CBA?

A. Yes. I have identified issues with the following benefits claimed by NS Power:

1. Critical Peak Pricing rate structure savings
2. Load balancing savings
3. Avoided net meters

Critical Peak Pricing Benefits

Q. Is the Critical Peak Pricing program a key component of the cost effectiveness of the AMI project?

A. Yes. A significant portion of the claimed benefits of AMI ($27 million) are associated with a hypothetical CPP rate structure. NS Power expects that this rate structure will induce average peak load reductions of 0.29 kilowatts (kW) (12.5 percent) for participating customers.[3,4] The primary source of benefits is the avoidance of additional generation capacity, achieved through an aggregate 26 megawatt (MW) reduction in peak demand.[5]

[3] NSPI Application, CI 47124 AMI Appendix A, page 11 of 21, and Appendix B02, tab "ReducedPeakGenerationCosts."

[4] NS Power assumes that no enabling technologies, for example communicating thermostats, are implemented along with the AMI project. If such enabling technologies were implemented, savings would likely increase, but costs would as well.

[5] NSPI (Synapse) IR-44 Page 1 of 2.

The $27 million in net benefits associated with the CPP program represents more than 70 percent of the overall net benefits of $38 million for the AMI project. [6] Thus, it is important to ensure that (a) the estimated benefits of the CPP project are reasonable and (b) the Company is committed to achieving these benefits.

Q. Please describe your concerns with NS Power's claimed savings associated with Critical Peak Pricing.

A. I have three primary concerns associated with the claimed benefits associated with the Company's proposed CPP program:

1. The projected peak demand reductions attributable to CPP may overestimate what is reasonably achievable in Nova Scotia, unless there is a greater level of customer participation in the CPP program than NS Power estimates;

2. NS Power's projected capacity deficit in 2022 is small and might not occur.[7] This could reduce the benefits of the CPP program and the AMI project as a whole, unless NS Power directly considers additional need arising from accelerated retirement of any thermal plants; and

3. The benefits are contingent upon a tariff that NS Power has not yet proposed. If the Company does not implement the CPP program, the associated benefits will not be realized.

Q. Please explain why the peak demand reductions assumed by NS Power might be overstated.

A. Critical peak pricing is a rate design in which customers face a very high price per kilowatt-hour—often several times higher than the average rate—during a few "critical events" during the year. These critical events are typically announced a day in advance, and they generally last four to eight hours. There is no doubt that Critical Peak Pricing can help achieve demand reductions by encouraging customers to shift their usage away from peak hours. The question, however, is by how much. The answer is dependent upon (a) average reductions per customer and (b) the level of participation in the program.

[6] NSPI Application, Figure 1: Summary of Cost Savings, page 22 of 93 and Figure 11, page 66 of 93.

[7] See for example, Synapse Evidence of David White, August 16, 2017 in M08087, NSPI's 2017 Load Forecast.

Many time-varying price pilots have been conducted to date, but the peak reduction results range widely. Further, very few CPP pilots have tested winter peak reductions in cold climates. Of the 57 time-varying price pilots listed in *Arcturus 2.0: A Meta-Analysis of Time-Varying Rates for Electricity*, only six tested CPP in the winter.[8] Thus, simply implementing a CPP rate does not guarantee substantial winter peak reductions.

Q. Have any utilities in similar climates tested a CPP rate?

A. Yes, I am aware of two CPP pilots that would be particularly applicable: one in Ontario and the other in Quebec.

Q. What were the results of the CPP pilots in Ontario and Quebec?

A. The results of the Ontario Energy Board Smart Price Pilot show that customers shifted a significant amount of load away from critical peak periods in August, but no statistically significant shift was found in January—except in one instance where load actually increased.[9] This is shown in Figure 1, below. Ontario differs from Nova Scotia in that it has a smaller percentage of customers with electric heat, which can be used as a source of demand reduction in the winter (14 percent in Ontario[10] compared with 27 percent in Nova Scotia).[11]

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[8] Ahmad Faruqui, Sanem Sergici, and Cody Warner, "Arcturus 2.0: A Meta-Analysis of Time-Varying Rates for Electricity," *The Electricity Journal* 30, no. 10 (December 2017): 64–72. Also available at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Rates/2017%20Arcturus%202%200%20(10-12-2017).pdf

[9] IBM Global Business Services and eMeter Strategic Consulting, Ontario Energy Board Smart Price Pilot Final Report, July 2007, page 4. Available at https://www.oeb.ca/documents/cases/EB-2004-0205/smartpricepilot/OSPP%20Final%20Report%20-%20Final070726.pdf

[10] Statistics Canada, Environment Accounts and Statistics Division, Type of main heating fuel used, by province, 2011, available at http://www.statcan.gc.ca/pub/11-526-s/2013002/t002-eng.pdf

[11] Response Synapse IR-38 (a).

Figure 1. Ontario CPP pilot results

Critical Peak Day (Entire Peak Period)	Summertime Load Shifting	Actual Max Temp (°C)	Actual Max Humidex
Friday, August 18	27.7%	30.0	35
Tuesday, August 29	10.1%	25.2	28
Thursday, September 7	n/s	22.4	n/a
Friday, September 8	n/s	26.5	31
	Wintertime Load Shifting	**Actual Min Temp (°C) During Peak Period**	
Tuesday, January 16	n/s	-18.7	
Wednesday, January 17	-7.2%	-16.1	
Friday, January 26	n/s	-21.3	

Statistically significant load shifting was detected for the first two summertime and the second wintertime critical peak events – though the winter result is counterintuitive. Seven critical peak events (against a target of nine) were called during the pilot using forecast temperature thresholds of 28°C in summer (or a Humidex above 30°C) and -14°C in winter. Results are statistically significant at the 90% level, unless denoted by "n/s".

Source: Ontario Energy Board Smart Price Pilot Final Report, July 2007.

In Quebec, a pilot was conducted in which customers faced critical peak prices more than three times higher than the off-peak price. These customers reduced load during peak periods by an average of 6 percent (0.27 kW).[12] However, 85 percent of households use electric heat in Quebec[13] compared to only 27 percent for NS Power.

Q. What do these pilots suggest regarding average per-customer peak demand reductions that can be expected in Nova Scotia?

A. The results of the Ontario and Quebec pilots indicate that CPP programs may produce very different results in winter-peaking utilities than in summer-peaking utilities. While 10 to 15 percent peak load reductions have been frequently observed at summer peaking utilities, the results from Ontario and Quebec suggest that lower peak reductions may occur in winter-peaking utility territories.

Further, the prevalence of electric heat may affect the results. Where electric heat is less common (such as in Ontario), very little load shifting was achieved. In contrast, Quebec

[12] HQD, Rapport Final Du Projet Tarifaire Heure Juste, Demande R-3740–2010, August 2010, page 30, available at http://www.regie-energie.qc.ca/audiences/3740-10/Demande3740-10/B-1_HQD-12Doc6_3740_02aout10.pdf

[13] Statistics Canada, Environment Accounts and Statistics Division, Type of main heating fuel used, by province, 2011, available at http://www.statcan.gc.ca/pub/11-526-s/2013002/t002-eng.pdf

was able to achieve an average peak reduction of 0.27 kW per customer, similar to the average load reduction projected by NS Power. However, NS Power may find it difficult to achieve this average per-customer load reduction, given that Quebec has more than three times the penetration rate of electric heat than Nova Scotia (85 percent compared to 27 percent).

For these reasons, it would be reasonable to assume that CPP in Nova Scotia will result in a much lower peak load reduction than 0.29 kW (12.5 percent). If the load reduction were scaled based on the ratio of electric heat in Quebec relative to Nova Scotia, the expected per-customer load reduction in Nova Scotia would be only 0.09 kW, or 4 percent. A more optimistic assumption would be that Nova Scotia could achieve the same percentage reduction in load as Quebec (6 percent), which would be equal to 0.14 kW peak reduction per customer.

Q. How would a 4 to 6 percent average CPP peak load reduction impact the cost-benefit analysis?

A. If the average peak reduction achieved by a CPP program were 6 percent rather than 12.5 percent, the net benefits of the project would be cut in half, falling from $38 million to [redacted].[14] If the average peak reduction achieved by a CPP program were 4 percent, the net benefits would decline to [redacted]. While this change would not in itself make the AMI project uneconomic, it increases the risk that if other assumptions also turn out to be overly optimistic, the project will no longer be cost-effective. For example, under a scenario in which no CPP benefits were realized and deployment capital costs increased by 10 percent,[15] the project would no longer be cost-effective.

Q. What has the Company assumed regarding customer participation rates?

A. In its application, the Company estimated participation rates of 15 percent associated with an opt-in CPP program.

[14] Analysis conducted using NSPI's Excel model as provided in Appendix B02.

[15] In AMI Application Synapse IR-5 Attachment 1 Page 2 of 2, NS Power finds that an increase in deployment capital costs of 10 percent would reduce the net benefits by $12.8 million. If the CPP benefits were also not realized, then the net benefits would fall from $38.1 million to -$1.7 million.

Q. Could the Company achieve higher participation rates?

A. Yes. The most direct way to achieve higher participation rates would be to implement an opt-out program, as opposed to an opt-in program.

Q. Would higher participation rates potentially offset the lower average per-customer load reductions?

A. Yes, it is reasonable to expect that higher participation rates from an opt-out program design would offset some or all of the lower average per-customer load reductions.

Q. What do you recommend regarding the Company's CPP assumptions?

A. I have four recommendations:

1. The Company should revise its base case assumptions to better reflect the average per-customer load reductions achieved by winter-peaking utilities.
2. The Company should also model an opt-out CPP case to determine whether higher participation levels would offset the lower average per-customer reductions.
3. The Company should evaluate alternative scenarios for the AMI project in which several costs or benefits are adjusted to be "favorable" and "unfavorable" – that is, "best case" and "worst case" scenarios.
4. When developing its proposed time-varying rate design, the Company should investigate both opt-out and opt-in options.

Q. Do you have any concerns regarding the Company's estimated avoided generation capacity costs?

A. Yes. The Company estimates that [redacted] in avoided generation capacity benefits (discounted) will be achieved in 2022 as a result of the CPP program. Based on the Company's 10 Year Load and Resources Outlook, however, it is likely that the generation capacity would be deferred, rather than completely avoided—unless (as noted) the Company accelerates retirement of thermal units beyond what is reflected in its current Load and Resource Outlook. Thus, the current level of avoided generation capacity benefits should be reduced to reflect a deferred investment, rather than an entirely avoided investment, unless the Company indicates a potential change to its capacity balance as currently reflected in the Load and Resource Outlook.

Q. Why would generation capacity likely be deferred, rather than avoided, presuming the Company's current Resource Outlook?

A. The Company's most recent 10 Year Load and Resources Outlook projects a small capacity deficiency of 15 MW beginning in the winter of 2022–2023, growing to a 31 MW capacity deficiency in 2026. Figure 24 from the Company's Load and Resources Outlook is reproduced below.

Load and Resources Outlook for NSPI - Winter 2017/2018 to 2026/2027
(All values in MW except as noted)

		2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027
A	Firm Peak Load Forecast	2,013	2,043	2,075	2,097	2,126	2,158	2,178	2,196	2,209	2,227
B	DSM Firm[1]	20	32	46	59	73	86	99	112	126	141
C	Firm Peak Less DSM (A - B)	1,993	2,010	2,029	2,038	2,054	2,073	2,080	2,084	2,082	2,086
D	Required Reserve (C x 20%)	399	402	406	408	411	415	416	417	416	417
E	Required Capacity (C + D)	2,391	2,412	2,435	2,445	2,464	2,487	2,496	2,501	2,499	2,503
F	Existing Resources	2375	2375	2375	2375	2375	2375	2375	2375	2375	2375
	Firm Resource Additions:										
G	Thermal Additions[2]	33			-153						
H	Biomass[3]	43									
I	Community Feed-in-Tariff[4]	8	9	3							
J	Tidal Feed-in-Tariff[5]	0.4	0.5	1							
K	Maritime Link Import				153						
L	Total Annual Firm Additions (G + H + I + J + K)	84	9	4	0	0	0	0	0	0	0
M	Total Cumulative Firm Additions (L + M of the previous year)	84	94	97	97	97	97	97	97	97	97
N	Total Firm Capacity (F + M)	2459	2468	2472	2472	2472	2472	2472	2472	2472	2472
	+ Surplus / - Deficit (N - E)	67	56	37	27	8	-15	-24	-29	-27	-31
	Reserve Margin % [(N - C)/C]	23%	23%	22%	21%	20%	19%	19%	19%	19%	19%

The Company estimates that it can reduce peak demand by [redacted] through the CPP program, 4 MW through the load balancing program, and approximately [redacted] through bill alerts. Under the Company's assumptions, these programs would allow NS Power to reduce demand by approximately 31 MW—just enough to avoid the additional generation capacity that it estimates would be needed in the Load and Resources Outlook. However, complete avoidance of the generation capacity may be unreasonable because:

- As discussed above, the Company's estimated CPP per-customer peak load reductions are overstated, as they do not reflect experience with CPP for winter-peaking utilities.
- NS Power would likely face additional need if it pursues accelerated retirement of its thermal plants.
- The load balancing estimates have not been well documented and could be overstated, as discussed in greater detail below.

Q. What do you recommend regarding the estimated generation capacity benefits?

A. The Company should modify the estimated generation capacity benefits to reflect a deferral value, rather than full avoidance.

Q. Do you have any other concerns regarding the CPP program?

A. Yes. A large portion of the benefits associated with AMI are contingent upon a tariff which NS Power has neither proposed nor documented. If the Company does not implement the CPP program, the associated benefits will not be realized. While the Company has stated that it will propose such a tariff, there is currently no requirement that the Company do so, and there is no proposed tariff to gauge the effectiveness or level of uptake.

Q. What do you recommend?

A. I recommend that, prior to approval to proceed with AMI, NS Power should develop a proposed tariff and conduct a more in-depth analysis of potential benefits under both opt-in and opt-out scenarios. Further, I recommend that this tariff be developed in close coordination with stakeholders, both to ensure that the tariff design has the greatest chance of success and to improve customer awareness and enthusiasm for the program.

<u>Load Balancing Savings</u>

Q. What are the benefits associated with improved load balancing?

A. NS Power contends that AMI may provide benefits associated with better load balancing, including reduced losses and avoided capacity costs.[16] These benefits arise from being able to more quickly, precisely, and efficiently respond to system needs.

Q. How does NS Power currently balance load?

A. NS Power's current process to balance load is done well after-the-fact and requires visits to the substation site for measurements and subsequent adjustments.[17] Based on this, I believe it is reasonable to assume that there could be benefits from the more efficient,

[16] NS Power application, p. 32.

[17] NSPI (UARB) IR-13.

timelier load balancing, such as that enabled by AMI. However, such benefits could potentially be attained through other means, such as substation feeder metering upgrades.

Q. What is the magnitude of the benefits associated with load balancing that NS Power projects?

A. NS Power estimates an NPV of $18.7 million in savings associated with load balancing.[18]

Q. How did NS Power estimate these benefits?

A. NS Power modeled peak loss reduction from balancing loads using CYME International Inc.'s Load Balancing Analysis. NS Power took the average Mega Volt Amperes (MVA) saved for three substations (45.2 kW) and divided it by the average MVA of those three substations (30 MVA). This resulted in an estimate of 1.5 kW of potential savings for every MVA of substation transformer capacity.[19]

Q. Have you reviewed the Company's modeling to estimate savings from load balancing?

A. No. I have not reviewed the detailed CYME modeling and therefore do not have comments on the rigor of this analysis.

Q. Do you have any concerns with the Company's selection of substations for calculating load balancing benefits?

A. Yes. NS Power's selection of substations for modeling the savings from load balancing is poorly documented. If the chosen substations are not representative of all substations in NS Power's system, the Company's claimed benefits from load balancing could be overstated.

NS Power states that these substations were selected "as geographic and load-type representative substations of the provincial network with readily available historical data."[20] NS Power further indicates that the chosen substations "are considered representative of typical substations on the NS Power system, representing urban, suburban and rural load types, with a variety of transformer sizes and customer counts."

[18] NS Power application, p. 22.

[19] NSPI (CA) IR-118.

[20] NSPI(CA) IR-118.

Based on its response to UARB IR-14, it appears that NS Power also took into account for its sample selection long single phase runs as found at the end of long rural feeders, conductor types found on the feeders, line construction, and transformer age.[21] However, NS Power did not provide any system data to support its assertions that these substations are representative along any of these dimensions, nor did it justify why these criteria are the most important ones to consider. It may well be that these substations were chosen for balancing because there were specific concerns about them. If that was the case, then in a statistical sense there would be a selection bias.

Further, the Company did not provide historical losses for any of these three substations or for other substations on its system. NS Power stated that, "while detailed data from the three representative substations has been gathered as part of the load balancing analysis, many NS Power substations do not have data readily available, so a comparison of losses over the past five years is not possible." Curiously, NS Power expects that the losses from the three substations to be representative of substations across the province, despite apparently not having data on losses from other substations.

Q. Do you have any other concerns with the Company's analysis of load balancing benefits?

A. Yes. I have three other concerns.

First, transferring load onto other phases or circuits may require additional investments, for example, where there are long, single phase lines. If the Company is claiming benefits associated with load balancing, then any additional costs of achieving those benefits should be included too. However, it appears that the Company has not included additional capital costs that would be required to enable better load balancing.

Second, the benefits attributed to AMI should only be the difference between what is readily achievable using existing load balancing methods and what can be achieved with AMI. However, NS Power has given no indication of what can be achieved using current methods, nor has it provided any estimates of savings achieved from historical efforts.[22]

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[21] NSPI(UARB) IR-14b.

[22] NSPI(UARB) IR-13.

The claim that the Company has no such data appears specious; savings calculations would likely be done on a prospective basis prior to initiating load balancing efforts. In addition, these data would likely be used in the context of area planning studies.

Third, it is possible to achieve load balancing savings without implementation of AMI. For example, NS Power could put interval meters on each phase of the substation distribution lines, likely for lower cost than implementing AMI system-wide. NS Power has not indicated whether it has considered measures to improve load balancing without AMI. A thorough economic analysis should consider to what extent the benefits could be achieved in other ways, and at what cost.

Q. What do you conclude about the Company's estimate of load balancing benefits?

I find that NS Power has not provided adequate data to be able to assess whether its load balancing savings are reasonable. Thus, NS Power's estimate of projected savings should not be taken at face value, and actual savings could be significantly less than claimed by the Company.

<u>Avoided Net Meters</u>

Q. What benefits does the Company estimate associated with avoided net meters?

A. The Company states that it expects to use communicating net meters for customers with distributed energy resources (such as rooftop solar) in the future. Because AMI meters would have this capability, the Company projects that it would avoid $4.4 million (present value) in communication operating costs for the distributed generation meters.[23]

Q. Are the net metering operating savings well justified?

A. No. The Company's assumptions regarding the rate of growth of net metering customers, and thus meters which would require additional operating cost, has not been adequately justified. In particular, the Company has provided insufficient information to assess whether the following two assumptions are reasonable:

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[23] Application, page 33 of 93.

1. Distributed solar in Nova Scotia will reach grid price parity in 2021, and
2. The rate of growth of net metered solar installations will resemble the growth rates seen in Massachusetts.

Q. Please describe NS Power's distributed solar forecast and how the forecast was developed.

A. NS Power projects that distributed solar will grow extremely rapidly through 2022 and then begin to taper off. Specifically, NS Power forecasts the following year-on-year growth rates for 2020 through 2025:[24]

2020	96%
2021	126%
2022	110%
2023	52%
2024	49%
2025	10%

The Company states that the 2019–2020 growth rate is due to local programs (e.g., Halifax Solar City and Provincial Department of Energy Solar for Community Buildings Pilot program), while the growth rates for the four years after parity is achieved (2021) reflect Massachusetts growth rates experienced in the four years after parity in that state.[25]

Q. Please explain what is meant by "price parity."

A. The Company defines price parity (also called "grid parity") as "when the cost to produce solar electricity is essentially the same as the cost to purchase electricity from the local distributor."[26]

[24] NSPI (Synapse) IR-30.

[25] NSPI (Synapse) IR-30(a-b) Page 2.

[26] NSPI (Synapse) IR-30(a-b) Page 1.

Q. How did NS Power estimate that solar in Nova Scotia would reach price parity in 2021?

A. The Company states that this estimate was arrived at "based on expected NS Power rates and the expected market costs of solar installations."[27]

Q. Did the Company provide any data or calculations to support this conclusion?

A. No, it did not.

Q. What data should be analyzed to determine whether it is reasonable to assume that Nova Scotia will reach price parity in 2021?

A. A thorough analysis of when price parity will occur should be based on transparent and well-documented data regarding:

- Retail rates (including both historical trends and future projections)
- Rooftop solar costs (including both historical trends and future projections)
- Financial incentives to the customer (also accounting for expiration of such incentives)
- Average installed capacity (kW) per customer and expected generation (in kilowatt hours or kWh)
- Average customer electricity consumption

Q. If price parity were to occur in 2021, would the growth trajectory in Nova Scotia likely follow that of Massachusetts?

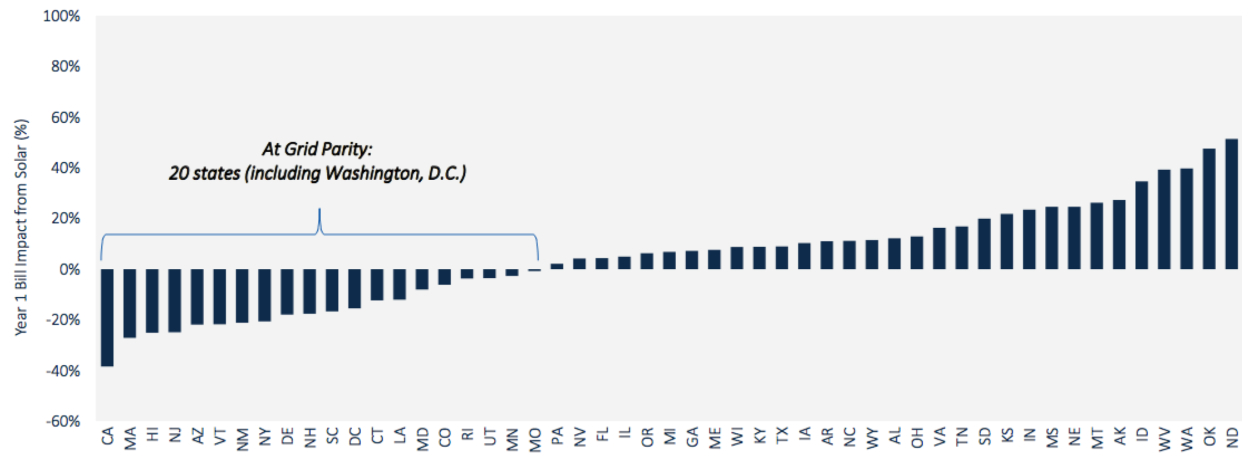
A. Not necessarily. Growth of distributed solar is closely linked to customer bill savings. Customer bill saving are often expressed in terms of a simple payback period—that is, the number of years it will take until the customer recoups his or her investment. Very short customer payback periods tend to produce rapid growth in distributed generation, but less attractive economics will produce lower rates of growth.

Price parity is one indicator of the economic attractiveness of solar, but it is a rough indicator. For example, in 2016 Green Tech Media (GTM) found that 20 U.S. states had reached price parity, but with different levels of savings for customers, as shown in

[27] NSPI (Synapse) IR-30(a-b) Page 2

Figure 2 below.[28] According to GTM's research, Massachusetts customers could expect the second-most attractive economics for installing solar due to various policies such as Solar Renewable Energy Certificates (SRECs) that provided significant additional financial incentives.

Figure 2. Solar price parity by state



Note: Grid parity metrics account for all NEM and rate reforms currently in effect for modeled utilities.

Q. Have the differences in savings across the states impacted the rate of solar adoption?

A. Yes. Because of these varying levels of savings, the year-on-year growth rates have also varied significantly across the states. The year-on-year growth rates for each of the 20 states that have achieved grid parity is shown in the table below, along with NS Power's projections for the years leading up to, and immediately after, achieving grid parity.

[28] Greentech Media. 2016. "U.S. Residential Solar Economic Outlook 2016-2020: Grid Parity, Rate Design and Net Metering Risk." https://www.greentechmedia.com/research/report/us-residential-solar-economic-outlook-2016-2020#gs.FKf12Y0.

Table 2. Solar growth rates of states that have achieved grid parity

	2012-2013	2013-2014	2014-2015	2015-2016
AZ	254%	42%	34%	27%
CA	104%	46%	50%	34%
CO	31%	39%	27%	14%
CT	49%	83%	109%	54%
DC	45%	36%	6%	82%
DE	26%	42%	48%	68%
HI	86%	28%	22%	13%
LA	177%	73%	27%	11%
MA	225%	101%	105%	48%
MD	51%	73%	102%	118%
MN	22%	38%	47%	41%
MO	142%	90%	15%	26%
NH	79%	42%	87%	75%
NJ	37%	31%	40%	56%
NM	429%	22%	27%	40%
NY	473%	84%	89%	49%
RI	38%	46%	88%	126%
SC	51%	49%	70%	518%
UT	172%	64%	93%	160%
VT	63%	48%	43%	16%
	2018-2019	**2019-2020**	**2020-2021**	**2021-2022**
NOVA SCOTIA	75%	96%	126%	110%

Sources: NSPI (Synapse) IR-30 Page 3 of 3, Greentech Media 2016. U.S. Residential Solar Economic Outlook 2016-2020: Grid Parity, Rate Design and Net Metering Risk.

Q. What does this analysis indicate?

A. The table indicates that growth rates for solar in states that have achieved price parity can vary significantly and that more information (such as the level of expected customer savings or payback period) would be required to better estimate expected growth rates in Nova Scotia.

Q. Did the Company compare this forecast of solar growth to any forecasts in its Integrated Resource Plans?

A. No. The Company states that its most recent Integrated Resource Plan did not contain any solar growth forecasts.[29]

[29] NSPI (Synapse) IR-30 (c).

Q. Has the Company developed any other solar growth forecasts since its most recent IRP?

A. No.[30]

Q. What do you recommend?

A. I recommend that the Company conduct additional analyses to more accurately estimate when price parity will occur and what growth rates can be expected given customer payback periods (or other measures of the magnitude of customer savings). Until then, a more conservative estimate of operating savings from avoided net meters should be assumed.

<u>Assumed life of AMI meters</u>

Q. What is your concern regarding the assumed useful life of the meters?

A. As I argued in my evidence in the pilot case, the assumption in the CBA that the meters will have a 20-year useful life may be optimistic. Assuming a shorter, more reasonable life would reduce the net benefits associated with the roll-out.

Q. Why do you think a 20-year useful life is optimistic?

A. I believe that the assumption for AMI meter life should be shorter than 20 years for the following three reasons:

1. Unlike analog meters, advanced meters are likely to have a much shorter useful life due to reliance on information and computing technologies, component failure, and the risk of technology obsolescence.

2. The AMI meters in NS Power's AMI proposal have warranties just for five years while the claimed useful life is 20 years.

3. Other jurisdictions—even New Brunswick Power, which is planning to deploy an [redacted] AMI meter procured through the same consortium as NS Power—use a more conservative, shorter asset useful life for AMI meters in order to mitigate risks associated with technological obsolescence or component failure.

[30] NSPI (Synapse) IR-30 (d).

Q. From a technological perspective, why do you think a 20-year useful life assumption might be too long?

A. The Office of the Auditor General of Ontario reports that even a 15-year useful life may be overly optimistic because smart meters (a) are subject to significant technological changes, (b) have complex features such as radio communications and digital displays, (c) are similar to information technology, computer equipment, and electronic devices in that they have short warranty periods and require substantial upgrades or more frequent replacements as the technology matures, and (d) will likely be obsolete by the time they are re-verified every six to 10 years, as required by Measurement Canada.[31]

NS Power provides some evidence to show that [redacted] AMI product has capabilities to support expanded services and potential future initiatives in order to mitigate the risk associated with premature product obsolescence.[32] While I agree that such capabilities offer some assurance for the AMI product being useful and current, it is still questionable that the capabilities will guarantee usefulness over the next 20 years. Technological advancements are so rapid that there is a high chance that better products will be available and make the AMI product obsolete before reaching the end of the 20-year term.

Furthermore, the proposed AMI capabilities will not change the fact that AMI meters are largely composed of information and computer technologies which tend to have a shorter life than other products.

Lastly, the [redacted] claim of a 20-year measure life is based on its own test.[33] This self-test has not been verified by any independent entities.

Q. Are you aware of other jurisdictions using a shorter useful life assumption for meters?

A. Upon the recommendation of the Staff of the Maryland Public Service Commission, Baltimore Gas and Electric (BG&E) reduced its analysis period from 15 years to 10 years

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[31] Office of the Auditor General of Ontario, 2014 Annual Report, Tabled in the Legislative Assembly of Ontario on December 9, 2014, at 391. Available at http://www.auditor.on.ca/en/content/annualreports/arbyyear/ar2014 html.

[32] NS Power response to Synapse IR-46 and Appendix B05, page 4.

[33] NSPI UARB IR-32.

in order to make a more conservative business case.[34] In addition, New Brunswick Power reduced its assumption for meter useful life from its original estimate of 20 years to a 15-year useful life. Its reason for doing so was in consideration of "the rapid changes in technology over the last 10 years and those expected in the next 10 years" in its current general rate case.[35] The latter case is particularly relevant to NS Power's case, because New Brunswick Power is a member of the AMI procurement consortium that NS Power also has joined, and New Brunswick Power's proposed project relies on [redacted] that are nearly identical to the meter technologies proposed by NS Power.[36]

Q. Please describe the warranties provided for NS Power's AMI project.

A. In the proposed AMI project, [redacted] provided by [redacted] are warranted just for [redacted], respectively.[37] Under these warranties, [redacted] will repair defects and cover cost of shipment back to the utility. [redacted] are available, but the costs of such warranties are not included in NS Power's AMI proposal. In addition, the longest warranty available from [redacted] is just [redacted]. This concerns me in that the manufacturer does not want to guarantee a full 20-year operation without any defects. Furthermore, the Company's response to NSUARB IR-51 indicates that the annual failure thresholds [redacted] These failure rates are inconsistent with the 0.5 percent yearly failure rate claimed by [redacted].[38]

Q. What is your recommendation for a useful life for NS Power's AMI?

A. I recommend NS Power use a more conservative useful life of 15 years in order to mitigate potential technological and financial risks associated with the proposed AMI project. Based on NS Power's response to NSUARB IR-49, revenue requirements in

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[34] Maryland Public Service Commission, Order 83531, In the Matter of the Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for the Recovery of Cost, Case 9208, August 5, 2010, available at: http://webapp.psc.state md.us/intranet/casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C:\Casenum\9200-9299\9208\\82.pdf.

[35] New Brunswick Power Corporation, 2017, Evidence for Matter 375 - 2018/19 General Rate Application, October 5, 2017, page 190.

[36] CONFIDENTIAL CI 47124 AMI Appendix B03.

[37] NS Power (NSUARB) IR-51.

[38] NS Power (NSUARB) IR-32.

NPV be reduced by approximately $20 million with the 15-year term, resulting in approximately $18 million savings instead of $38 million savings under the 20-year term.

NS Power's sensitivity analysis of key assumptions

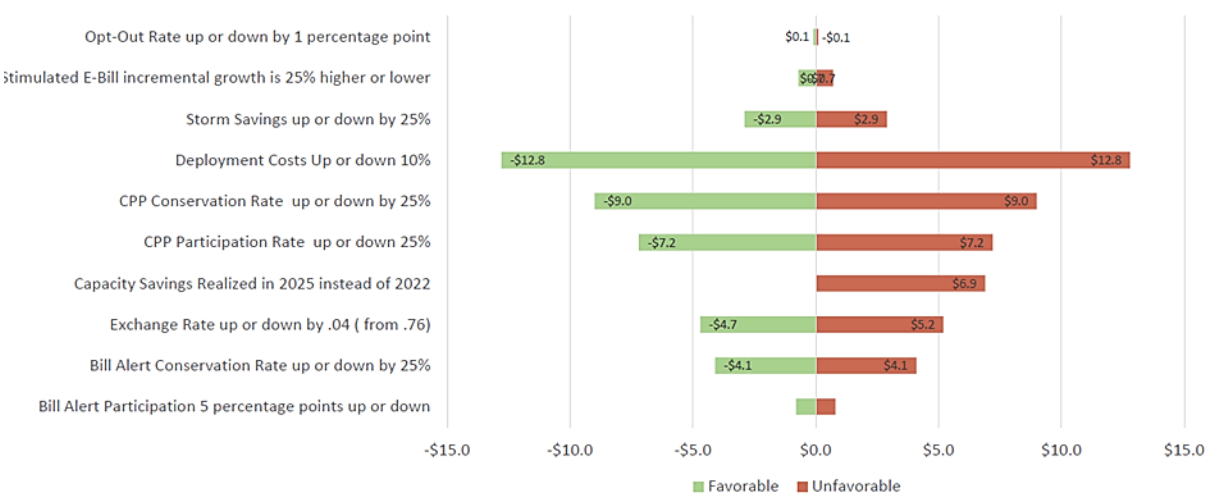
Q. Did NS Power conduct a sensitivity analysis on the cost savings with the AMI business case besides AMI's useful life?

A. Yes. In response to Synapse IR-5, NS Power provided assessments of the impact of changes in several benefit and cost categories on the NPV of the revenue requirement of the AMI project.

Q. What were the results of this analysis?

A. The results of this analysis are shown in Figure 3, below, in terms of potential changes in NPV due to certain sensitivity factors

Figure 3. Change in NPV of revenue requirement ($ millions)



Source: NSPI (Synapse) IR-5.

The analysis shows that the NPV of revenue requirements is sensitive to some of NS Power's assumptions, including deployment costs and CPP conservation rate. As noted earlier in my evidence, the 12.5 percent assumption for CPP savings may be too optimistic; a 6 percent rate (about 50 percent of NS Power's assumption) may be more appropriate. This suggests that a higher variance in CPP conservation rate should be analyzed.

An unfavorable outcome in any single one of these dimensions would be unlikely to result in the AMI project becoming uneconomic (i.e., change the present value of the net projected benefits from positive to negative). However, in combination with each other, and with variation in the realized benefits associated with load balancing and in the life of the AMI meters (as discussed earlier in this evidence), these factors could overwhelm NS Power's projected net benefits of $38 million. For example, combining just the two sensitivities for increased deployment costs and reduced CPP conservation rates would make the project uneconomic if the useful life is 15 years (as discussed in the previous section).

Q. What do you recommend?

A. The Company should evaluate the cost-effectiveness of the project using various scenarios in which several costs or benefits are adjusted to be "favorable" and "unfavorable" simultaneously in order to better understand the potential benefits to customers under a "best case" scenario and the potential risk to customers under a "worst case" scenario.

5. COORDINATION WITH EFFICIENCYONE

Q. Are there benefit opportunities that have not been addressed in NS Power's filing?

A. Yes. The information obtained from AMI could be used to more effectively target energy efficiency offerings. Without a framework for sharing data with EfficiencyOne, the benefits that customers would experience and the cost savings to the utility system from implementation of AMI may be unnecessarily limited.

Q. Has NS Power developed a proposal for coordinating with EfficiencyOne?

A. No. In response to discovery, NS Power indicated that it "has not yet considered the extent to which the data acquired from AMI may be made available to other parties."[39]

[39] NSPI EAC IR-7.

Q. Has the Board issued guidance on how NS Power is to share information with EfficiencyOne?

A. Yes. On November 15, 2017 the Board issued an order in case M08113 regarding information transfer between NS Power and EfficiencyOne. This order required NS Power to disclose names, emails, and customer usage data to EfficiencyOne on a monthly basis.

Q. Do you have any recommendations regarding data sharing?

A. Yes. In light of the Board order, I recommend that NS Power and EfficiencyOne revisit the fields for data transfer, given that AMI will produce more data than are currently available to NS Power. If NS Power and EfficiencyOne cannot reach an agreement about data transfer protocols, they should apply to the Board.

6. EXISTING METERS WILL NO LONGER BE USED AND USEFUL

Q. What will happen with the current, conventional meters that NS Power wants to replace with AMI meters?

A. The currently installed meters will be removed from service. NS Power does not anticipate that the currently installed meters will have any salvage value.[40] Once they have been removed, they will no longer provide service to customers. NS Power plans to classify these meters as not used and useful after they are removed from service.[41]

Q. Is there any undepreciated cost of the existing meters?

A. Yes. The undepreciated cost of the current meters was $19.5 million as of June 30, 2017.[42]

Q. What share of the existing meters have not yet reached the end of their expected operating lives?

A. NS Power claims that a significant portion of meters across the Province are at or approaching end of useful life.[43] However, its response to discovery tells a different story.

[40] NSPI(CA) IR-22.

[41] NSPI(UARB) IR-41.

[42] NSPI(UARB) IR-41.

[43] NS Power application, p. 6.

About a fifth of residential meters are less than five years old. Over a third of residential meters are less than 10 years old, and roughly half are less than 20 years old. Demand meters are even newer: about one-third are less than five years old, and two-thirds are under 10 years old.[44]

Q. How does NS Power propose to handle the undepreciated cost of the existing meters?

A. NS Power requests that the undepreciated cost of the asset be amortized, on a straight-line basis, over a five-year period.[45] NS Power maintains that these assets should remain in rate base until the costs have been fully amortized, consistent with its accounting policy.[46]

Q. Do you think NS Power's proposal is reasonable?

A. Not entirely. While it may be reasonable to allow NS Power to recover the costs of these meters, ratepayers should not have to pay for a return on the meters that have been removed from service.

Q. Please explain why it is not appropriate for NS Power to earn a return on the undepreciated meters.

A. Because the meters will have been removed from service, they are no longer used and useful. It would not be appropriate for customers to be assessed both the cost and a return on an asset that is no longer used and useful. Effectively, allowing recovery of and on both the existing meters and AMI meters would allow two sets of meters in rate base, which would create double recovery of metering costs.

Q. Are you aware of other jurisdictions that have disallowed return of and on meters to be replaced by AMI?

A. Yes. The Public Service Commission of Maryland allowed Baltimore Gas and Electric to recover costs of the meters to be replaced by AMI, but did not allow the company to

[44] NSPI (Synapse) IR-7.

[45] NS Power Application, p. 90.

[46] NSPI (UARB) IR-41.

continue to earn a return on the existing meters.[47] I understand that other jurisdictions have also not allowed full recovery of and on meters being replaced.

7. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. I make the following findings:

- NS Power reports that the AMI project is cost effective, with net benefits of $38 million. However, I find that the CBA includes benefits that are not well supported, omits certain costs, and does not adequately consider the downside risks in its sensitivity analysis of key inputs and assumptions. If adjustments are made to the costs and benefits as suggested herein, the CBA may determine that the project is not cost effective.
- Existing meters will no longer be used and useful.
- NS Power's application does not address coordination with EfficiencyOne and may miss savings opportunities as a result.

Q. Please summarize your primary recommendations.

A. I offer the following recommendations:

- A CPP tariff should be developed prior to Board approval of the AMI project.
- NS Power should adjust its CBA based on the comments in this evidence.
- NS Power should revisit its scenario analyses to determine its exposure if multiple sensitivity areas have negative outcomes.
- The Company should then file the results of the revised CBA and scenario analyses in this case for consideration by the parties.
- While recovery of the cost of existing meters may be appropriate, the Board should not allow a return on the existing meters.

[47] PSC of Maryland. June 3, 2016 order. In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates. Case No. 9406.

Q. Does this conclude your pre-filed evidence?

A. Yes, it does.

APPENDIX A: RESUME

Alice Napoleon, Senior Associate

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Senior Associate*, June 2013 – present; *Associate*, July 2008 – June 2013; *Research Associate*, April 2005 – July 2008.

- Conduct expert analysis, draft testimony, and provide litigation support regarding energy efficiency program design and performance, funding and incentive mechanisms, evaluation, cost-effectiveness screening, avoided costs, potential studies, and plans.
- Lead a team to develop a toolkit for energy efficiency program administrators to incorporate the energy performance program Superior Energy Performance™ into their portfolios. Develop case studies of existing energy efficiency program offerings that support implementation of strategic energy management by industrial customers.
- Provide ongoing expert consulting for the State of New Jersey regarding state- and utility-administered residential, low-income, commercial, industrial, and self-directed energy efficiency and combined heat & power programs and proposals, including review, analysis, comments, and testimony assistance.
- Facilitate residential, commercial, and industrial policy working groups and manage technical analysis of working group recommendations to reduce greenhouse gas emissions in Colorado, South Carolina, and Maryland.
- Sponsor testimony on energy efficiency plan and advanced metering infrastructure (AMI) proposals.
- Research historical emissions of criteria and hazardous air pollutants, greenhouse gases, and coal combustion wastes. Research and develop potential state and local emissions mitigation strategies, such as strategies for reducing ambient fine particulates in New York City.
- Conduct surveys of regional, state, and utility policies and practices regarding ratemaking for energy efficiency, power procurement, risk management, and fuel diversity.
- Research federal, regional, and state policies and case histories on integrated resource planning, power procurement, power plant operations, renewable portfolio standards, and market power.
- Monitor and analyze electricity, coal, and emissions allowance market data, models, and projections, as well as economic and policy developments that impact these markets.
- Write and edit reports, expert testimony, and discovery questions and responses.

Resource Insight, Inc., Arlington, MA. *Research Assistant*, 2003-2005.

Responsible for conducting research and analysis on electric, gas, steam, and water resource issues. Conducted discounted cash flow analysis for asset valuation; developed market-price benchmarks for analysis of power-supply bids using market and regulated prices for energy, capacity, ancillary services, transmission, and ISO services and adjusting for load shape, assignment of transmission rights, and losses. Prepared discovery responses, formal objections, comments, and testimony; collaboratively wrote and edited reports; created and formatted exhibits. Participated in drafting an Energy Plan for New York City. Edited solicitation for competitive power supply to serve aggregated municipal load.

University of Massachusetts, Amherst, MA. *Teaching Assistant*, 2001-2002.

Developed and taught lessons on applied math to a diverse group of incoming graduates; tutored students in microeconomic theory and cost benefit analysis; graded problem sets and memoranda.

International Council for Local Environmental Initiatives, Berkeley, CA. *Cities for Climate Protection Intern for the City of Northampton, MA*, 2001.

Compiled primary and secondary source data on energy consumption and solid waste generation by the municipal government, city residents, and businesses; applied emissions coefficients to calculate total greenhouse gas (GHG) emissions; identified current and planned municipal policies that impact GHG emissions; researched the predicted effects of global warming locally; gathered public feedback to provide acceptable and proactive policy alternatives. Composed a GHG emissions inventory describing research findings; wrote and distributed a policy report and press releases; gave newspaper and radio interviews; addressed public officials and the public during a televised meeting.

University of Massachusetts, Amherst, MA. *Research Assistant*, 2000-2001.

Located federal data sources, identified changes, and updated a research database to evaluate the Habitat Conservation Program; proofread articles and white papers; composed a literature review on land use modelling. Collaboratively administered, tested, and proposed interface enhancements for a web-based data warehouse of regional habitat change research; formally presented the system to an independent research group.

Court Square Data Group, Inc., Springfield, MA. *Administration Manager*, 1998-2000; *Project Administrator*, 1996-1998.

As Administration Manager, analysed profitability and diversity of income sources; managed cash flow, expense, and income data; created budgets; devised and implemented procedures to increase administrative efficiency; implemented new accounting system with minimal disruption to workflow.

As Project Administrator, coordinated implementation of software features; identified opportunities for future development; monitored problem resolution; wrote and coordinated production of a user's manual and questionnaires; edited technical proposals and a business plan.

EDUCATION

University of Massachusetts, Amherst, MA
Master of Public Administration, 2002

Rutgers University, New Brunswick, NJ
Bachelor of Arts in Economics, 1995

Syracuse University, Syracuse, NY, 1994

PUBLICATIONS

Fagan, B., A. Napoleon, S. Fields, P. Luckow. 2017. *Clean Energy for New York: Replacement Energy and Capacity Resources for the Indian Point Energy Center Under New York Clean Energy Standard (CES).* Synapse Energy Economics for Riverkeeper and Natural Resources Defense Council.

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Nova Scotia Utility and Review Board (Case No. M07767): Direct evidence in the matter of the NSPI Advanced Meter Infrastructure Pilot. On behalf of Counsel to the Nova Scotia Utility and Review Board. February 16, 2017.

Public Service Commission of South Carolina (Docket No. 2016-223-E): Direct Testimony of Alice Napoleon regarding South Carolina Electric and Gas Energy Efficiency Efforts. On behalf of South Carolina Coastal Conservation League. September 1, 2016.

Nova Scotia Utility and Review Board (Case No. M06247): Direct evidence in the matter of an application by Efficiency Nova Scotia Corporation for approval of its electricity demand-side management plan for 2015. On behalf of Counsel to the Nova Scotia Utility and Review Board. July 14, 2014.

TESTIMONY ASSISTANCE

Public Service Commission of South Carolina (Docket No. 2017-2-E): Direct Testimony of Thomas Vitolo, PhD regarding Avoided Cost Calculations and the Costs and Benefits of Solar Net Energy Metering for South Carolina Electric & Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. March 22, 2017.

State of New Jersey Board of Public Utilities (Docket No. ER16060524): Direct testimony of Tim Woolf regarding the Petition of Rockland Electric Company for Approval of an Advanced Metering Program, and for Other Relief. On behalf of New Jersey Division of the Ratepayer Advocate. September 9, 2016.

Nova Scotia Utility and Review Board (Matter No. M06733): Direct testimony of Tim Woolf regarding EfficiencyOne's 2016-2018 demand-side management plan. On behalf of the Nova Scotia Utility and Review Board. June 2, 2015.

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State of New Jersey Board of Public Utilities (Docket No. EO14080897): Direct testimony of Kenji Takahashi regarding the Petition of Public Service Electric & Gas Company to continue its Energy Efficiency Economic Extension Program on a Regulated Basis (EEE Extension II). On behalf of New Jersey Division of the Ratepayer Advocate. November 7, 2014.

Kentucky Public Service Commission (Case No. 2014-00003): Direct testimony of Tim Woof regarding Louisville Gas and Electric Company and Kentucky Utilities Company's proposed 2015-2018 demand-side management and energy efficiency program plan. On behalf of Wallace McMullen and the Sierra Club. April 14, 2014.

State of New Jersey Board of Public Utilities (Docket No. GO12050363): Direct testimony of Maximilian Chang regarding South Jersey Gas Company's proposal to extend and modify its energy-efficiency programs. On behalf of New Jersey Division of the Ratepayer Advocate. November 9, 2012.

New Jersey Board of Public Utilities (Docket No. GO12070640): Direct testimony of Robert Fagan regarding New Jersey Natural Gas Company's petition for approval of the extension of the SAVEGREEN energy efficiency programs. On behalf of the New Jersey Division of the Ratepayer Advocate. October 26, 2012.

State of New Jersey Board of Public Utilities (Docket No. GO11070399): Direct testimony of Robert Fagan regarding Elizabethtown Gas Company's Proposed Energy Efficiency Program. On behalf of New Jersey Division of the Ratepayer Advocate. December 16, 2011.

New Jersey Board of Public Utilities (Docket No. GR11070425): Direct testimony of Robert Fagan regarding New Jersey Natural Gas Company's petition for approval of the extension of the SAVEGREEN energy efficiency programs. On behalf of the New Jersey Division of the Ratepayer Advocate. November 16, 2011.

State of New Jersey Board of Public Utilities (Docket No. GR10030225): Direct testimony of David Nichols regarding New Jersey Natural Gas Company's Proposed Energy Efficiency Program. On behalf of New Jersey Division of the Ratepayer Advocate. July 9, 2010.

Virginia State Corporation Commission (Case number PUE-2009-00097): Direct testimony of William Steinhurst regarding Appalachian Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq. On behalf of the Southern Environmental Law Center, Chesapeake Climate Action Network, Appalachian Voices, and the Virginia Chapter of The Sierra Club. March 23, 2010.

Delaware Public Service Commission (Docket No. 07-20): Jointly authored an expert report, with Robert Fagan, William Steinhurst, David White, and Kenji Takahashi, In the Matter of Integrated Resource Planning for the Provision of Standard Offer Service by Delmarva Power & Light Company Under 26 DEL. C. §1007 (c) & (d). On behalf of the Staff of Delaware Public Service Commission. April 2, 2009.

New Jersey Board of Public Utilities (BPU Docket EM05020106): Direct and surrebuttal testimony of Bruce Biewald, Robert Fagan, and David Schlissel regarding the Joint Petition Of Public Service Electric and Gas Company And Exelon Corporation For Approval of a Change in Control Of Public Service Electric and Gas Company And Related Authorizations. On behalf of New Jersey Division of the Ratepayer Advocate. November 14, 2005 and December 27, 2005.

Illinois Commerce Commission (Dockets 05-0160, 05-0161, 05-0162): Direct testimony of William Steinhurst regarding Ameren's proposed competitive procurement auction (CPA). On behalf of Illinois Citizens Utility Board. June 15, 2005 and August 10, 2005.

Illinois Commerce Commission (Docket 05-0159): Direct testimony of William Steinhurst regarding Commonwealth Edison's Proposal to implement a competitive procurement process. On behalf of Illinois Citizens Utility Board and Cook County State's Attorney's Office. June 8, 2005 and August 3, 2005.

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